Hydrogen Infrastructure Options for Supplying Direct Hydrogen Fuel Cell Vehicles

By C.E. (Sandy) Thomas, Ira F. Kuhn, Jr., Brian D. James, Frank D. Lomax, Jr. and George N. Baum
Directed Technologies, Inc.
Arlington, Virginia

Storing hydrogen directly on fuel cell vehicles would eliminate the need for development and installation of complex onboard chemical processing plants to convert liquid hydrocarbon fuels to hydrogen. Direct hydrogen storage would also maximize the environmental and oil substitution attributes of the fuel cell vehicle, since onboard chemical processors necessarily reduce overall fuel economy and may still depend on gasoline as the primary fuel. However, to capitalize on these advantages of direct hydrogen fuel cell vehicles, an affordable infrastructure system must be developed to supply the necessary hydrogen. Industry is faced with a fundamental choice: a complex vehicle design and moderate (methanol) or no (gasoline) infrastructure impact, or a simplified and less costly vehicle design and the need for a new infrastructure development.

The two key attributes of such an infrastructure are hydrogen cost and capital investment. Low hydrogen cost is important, but capital investment requirements are more crucial. The needed investments must be flexible such that they can grow as needed to match the evolving fuel cell vehicle market penetration. For example, the cost of hydrogen produced by large central station steam methane reformer plants that can support half a million vehicles may be competitive with gasoline per mile driven, but it may be many years before there will be half a million fuel cell vehicles on the road. The industry needs smaller, more flexible options to produce and dispense hydrogen locally for small numbers of fuel cell vehicles.

This paper summarizes the results of a hydrogen infrastructure study funded by the Ford Motor Company under the U.S. Department of Energy cost-shared direct hydrogen fuel cell vehicle program. Directed Technologies, Inc. led this investigation, which included Air Products and Chemicals, BOC Gases, The Electrolyser Corporation, Ltd., and Praxair evaluating multiple hydrogen production options.

The Ford study identified a plausible path toward the development of a flexible and affordable hydrogen infrastructure to support the market penetration of fuel cell vehicles. The study identified potentially cost-effective options for both the long term, mature fuel cell vehicle market, as well as the short term transition phase, when fuel cell vehicles are highly dispersed or clustered in small fleets.

For the long term, Figure 1 summarizes the expected cost of hydrogen produced in large scale steam methane reformer plants located near sources of inexpensive ($2/MBTU) natural gas. All estimates include the cost of hydrogen production, transportation, compression, storage and dispensing into 5,000 psi compressed tanks onboard the fuel cell vehicles. Financial assumptions include a 10% real, after-tax return on investment, which translates into an 18.4% annual capital recovery factor. As shown in Figure 1, hydrogen could be delivered at a cost of about $3/kg.

This would be competitive with gasoline at $1.20/gallon, assuming that the fuel cell vehicle achieved a 2.4 times greater fuel economy than the equivalent gasoline-powered vehicle. For example, gasoline at $1.20/gallon would cost the same per mile as hydrogen at $2.85/kg with these assumptions.

Another option would be to build steam methane reformer plants on-site at the hydrogen dispensing station. This option eliminates the hydrogen transportation cost -- the natural gas pipeline becomes the primary infrastructure. Figure 2 shows the hydrogen cost estimates as a function of the plant size in terms of number of vehicles supported by the plant (divide these numbers by eight to determine the number of vehicles actually refueling each day). In general, the hydrogen costs increase with reduced plant size, as expected. At least one estimate by Praxair shows that hydrogen could be produced and delivered to a 5,000 psi tank for $2.27/kg, well below the target cost of hydrogen at $2.90/kg (equivalent to fully taxed gasoline at $1.20/gallon), and approaching the $1.90/kg target which is equivalent to wholesale gasoline at $0.80/gallon.

But even this Praxair on-site plant would produce enough hydrogen to support about 4,800 fuel cell vehicles. It will be many years before there would be 4,800 vehicles within range of a single refueling station. Furthermore, the cost of such a plant ($5.5 million) would be difficult to justify without the requisite vehicle users. We need smaller options in the beginning.

Two possible options for the early transition strategy are small scale, factory-built steam methane reformers or factory-built electrolyzers. Rather than achieving economies of scale by building huge hydrogen production plants at a central location, this paradigm achieves low cost through the economies of mass production in a factory. The hydrogen fueling appliances are manufactured in a central factory and shipped around the country, much like home furnaces or other home appliances.

Fortunately we already have one example of such a factory-built steam methane reformer. The front end of the IFC PC-25 200-kW phosphoric acid stationary fuel cell system is a steam methane reformer. The PC-25 is manufactured in South Windsor, Connecticut and shipped around the world. It is installed by the customer and operates unattended. IFC does not even send an engineer to supervise installation and start-up.

DTI has estimated the costs for a factory-built steam methane reformer for the transportation market based on the IFC technology. A pressure swing adsorption system, compressor, and storage system was added. The resulting hydrogen cost estimate for this factory-built system is compared with the Praxair system built on-site in Figure 3. The factory-built system is projected to produce less costly hydrogen, even though it supports fewer vehicles (about 300) than the Praxair unit at 4,800 vehicles.

However, Figure 3 assumes current low production volume manufacturing methods. With higher volume production, DTI projects the potential for further cost reductions in the fueling appliance, as indicated in Figure 4. We have also assigned cost scaling with size factors to extrapolate the cost of the PC-25 based technology to even smaller units. In this case, the delivered cost of hydrogen could be significantly less than the equivalent cost of wholesale gasoline for hydrogen appliances as small as 50 fuel cell vehicles. This is in the range of early fleet vehicle demonstration projects.

Another alternative would be to utilize the electrical power grid to "deliver" hydrogen instead of or in addition to the natural gas pipeline system. Small scale electrolyzer systems could be installed in very small sizes, including even home electrolyzers to supply hydrogen to just one or two vehicles. The Electrolyser Corporation is in fact developing such a device, coupling an electrolyzer to a compressor to fill the vehicle tanks. Again, this would be a factory-built appliance with the potential for cost reductions with mass production, as shown in Figure 5, based on manufacturing cost estimates developed in cooperation with The Electrolyzer Corporation and Ford Motor Company. With electrolyzers we project hydrogen costs competitive with gasoline for units as small as 10-vehicle appliances. Figure 5 assumes that off-peak electricity is available at 3 cents/kWh. However, with utility deregulation, at least one utility has suggested that off-peak electricity will be available at a price of 1.5 cents/kWh in the Chicago area beginning in early 1997. In that case, the cost of hydrogen would be competitive with fully taxed gasoline for units supporting just two or three fuel cell vehicles, and larger units could match the cost of wholesale gasoline in mass production for 10-car hydrogen appliances, as shown in Figure 6.

Finally, the required investment cost for hydrogen appliances per fuel cell vehicle is summarized in Figure 7. According to our projections, hydrogen refueling appliances could be produced at costs less than $500 per vehicle for electrolyzer systems, or as low as $150 per vehicle for the factory-built steam methane reformer in 10,000 quantity production units. Thus the total investment cost to the consumer for the hydrogen "infrastructure" could be less than the ambitious cost goal for onboard chemical processors of $20/kW, or $1,000 per vehicle for a 50-kW fuel cell system. The fuel cell vehicle cost could also increase with an onboard reformer, due to lower efficiency of the fuel cell operating on reformate, and due to extra weight forcing larger power train components to maintain vehicle acceleration.

The automobile industry choice of onboard chemical processing versus direct hydrogen storage is actually a choice of *where* fuel would be processed. Either liquid hydrocarbons are processed onboard the vehicle, or natural gas (or electricity) is processed at a stationary site to produce hydrogen. Stationary fuel processing has clear advantages with respect to warmup time, dynamic range, response time, weight, vibration, shock and temperature extremes. From an economic viewpoint, the stationary fuel processor is utilized at least 12 hours if not 24 hours a day at full power, whereas the onboard chemical processor is utilized an average of one hour per day, and then only at part power most of the time. The effective capacity factor for an onboard fuel processor is less than one percent, compared to an estimated capacity factor of 69% for a stationary hydrogen fuel appliance.

We conclude that the hydrogen infrastructure provided by factory-built steam methane reformers and factory-built electrolyzers could cost less than an onboard fuel processor. These hydrogen appliances provide the flexibility needed in order for the hydrogen infrastructure to grow incrementally with the fuel cell vehicle industry. Hydrogen fuel could be provided at costs competitive with gasoline, and the direct hydrogen fuel cell vehicle would provide greater environmental benefits and, depending on liquid hydrocarbon choice, greater energy security benefits than the onboard processing option.